Staff Report on:

AIR POLLUTANT EMISSIONS: TRENDS AND RESTRUCTURING IMPLICATIONS

Joseph M. Loyer

Environmental Protection Office
Energy Facilities Siting and Environmental Protection Division
California Energy Commission

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INTRODUCTION

The ***ER 96*** Committee asked staff, in the February 15, 1996 Issue Order, Issue I.C.2, to identify the possible effects on in-state and out-of-state emission trends of the restructuring of the electric generating sector in California. To address this question, staff first describes in this paper the current emission factors for existing electric generation resources both in and outside of California, as determined in the 1994 Electricity Report (***ER 94***). We then use the emission factors to compare the relative changes in emissions that would occur if generation shifts to various regions and/or sectors under restructuring. The uncertainties associated with restructuring restrict this paper to a qualitative analysis of possible changes in air pollutant emissions.

EMISSION FACTORS

It is important to recognize that <u>emission factors</u> are not emissions. Emission factors are the rates at which emissions are produced by the generation of electricity. This means that for every gigawatt-hour (GWh) of electricity generated there will be certain quantities of criteria air pollutants produced. For example, if the NO_x emission factor for California combustion turbines is 3,660 lbs/GWh, and if these combustion turbines produce 100 GWh of power in a given year, then the average NO_x emissions in that year would be 183 tons (i.e., 100 GWh * 3,660 lbs/GWh / 2000 lbs/ton). The analysis in this paper will be based on comparing emission factors of different regions, not actual emissions, since the size of the expected generation shifts, and the actual mix of generation technologies which will occur under restructuring are not certain.

California Emission Factors

TABLE 1 shows the emission factors for California electric generation technologies as they currently exist. We assume that California power plants use natural gas as their primary (and to a large extent, only) fuel source. The emission factors in **TABLE 1** for combined cycles are based on California Energy Commission (CEC) jurisdictional qualifying facilities, and have an average heatrate of 10,200 Btu/kWh. The emission factors for the alternative fuel boilers[1] are based on the non-jurisdictional qualifying facilities, and have an average heatrate of 15,000 Btu/kWh.

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[1] Alternative fuels include landfill gas, digester gas (biomass), waste water treatment gas, refuse derived fuels (landfill material that is burned directly or converted into fuel pellets), wood wastes, tires, and other similar waste fuels. These alternative fuels have high emission factors, but do not produce a significant amount of electricity. Therefore, it is not likely that they will represent a significant portion of the emissions inventory.

The emission factors for the utility boilers and combustion turbines in **TABLE 1** are based on Southern California Edison's (SCE) resource mix. The assumed heat rate for the utility boilers is 10,500 Btu/kWh, and for the combustion turbines is 13,900 Btu/kWh, consistent with the California Greenhouse Gas Emission Inventory, 1990.[2] On average, the utility boilers are 38 years old and combustion turbines are 22 years old.

TABLE 1
***ER 94* GENERALIZED EMISSION FACTORS**
FOR CALIFORNIA POWER GENERATION

Technology Type	**Capacity**	**Emission Factors (lbs/GWh)**					
	(MW)	**NO_x**	**SO_2**	**ROG**	**PM_{10}**	**CO**	**CO_2***
Combined Cycle	150	1,140	160	130	260	340	1,180,000
Utility Boiler	225	1,660	10	10	30	400	1,214,000
Utility Combustion Turbine	150	3,660	210	190	210	1,520	1,607,000
Alternative Fuel Boilers	< 50	11,800	7,380	2,760	670	8,450	4,971,000

* The CO_2 emission factors are based on the carbon content of the fuel and the average heat rates of the technology types. The carbon content for natural gas is 115.7 #CO_2/mmBtu and for the alternative fuels it is 331.4 #CO_2/mmBtu. This is based on the California Greenhouse Gas Emission Inventory, 1990.

TABLE 2 shows the emission factors used in ***ER 94*** for new resource additions. We assume that in-state additions and repowered facilities have this emission profile, which reflects advancements in technology and more stringent emission limits for Best Available Control Technology (BACT). The NO_x emission factor is 1/40th of the current in-state combined cycle. In addition, SO_2, ROG, PM_{10}, CO and CO_2 emission factors are lower.

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2 The California 1990 Greenhouse Gas Emission Inventory is currently being developed by California Energy Commission Staff.

TABLE 2
***ER 94* EMISSION FACTORS FOR NEW ADDITIONS AND REPOWER PROJECTS IN CALIFORNIA**
(lbs/GWH)

NO_x	SO_2	ROG	PM_{10}	CO	CO_2
40	10	65	45	45	925,000

Out-of-State Power

The emission factors in **TABLE 3** are weighted averages, which include hydro and nuclear (technologies which have no emissions) and span the years indicated. The out-of-state system-weighted average emission factors, shown in **TABLE 3** are based on those reported in ***ER 94***. ***ER 94*** projected how the out-of-state emission factors would change over time due to the changing resources in the respective out-of-state generation areas. The future resource mix over the next 10 years in the Southwest consists of new coal and gas-fired combined cycle power plants and the retirement of existing coal plants. In the Pacific Northwest, potential operational constraints on hydroelectric production which may result in a shift to fossil-fuel based generation technologies is the main cause of the change in system average emission factors. These resource changes are reflected in the weighted emission factors.

ER 94 also distinguished between dispatch blocks, the level at which the power plants will operate. **TABLE 3** reflects the emission factors for the final dispatch block. We assume that this is the case for the incremental purchases associated with restructuring, but in reality this may not be so. It is a fact that California utilities currently purchase power from out-of-state resources as off-peak, economy power (in part). This means that this power will be produced and sold at a lower dispatch block, with possibly lower efficiency and higher emissions. However, under restructuring it would be impossible to determine how economy power purchases are effected. To determine this effect would require information not currently available (such as how restructuring would be implemented, how out-of-state utilities would plan on participating, etc). For a discussion, more appropriate to this paper, we assume that the on-peak power purchases from out-of-state resources will continue at or increase beyond their current levels. Therefore, any additional on-peak power purchased should be supplied by the final dispatch blocks as represented in **TABLE 3**.

TABLE 3
***ER 94* EMISSION FACTORS FOR OUT-OF-STATE POWER GENERATION FOR SALE TO CALIFORNIA**

Region (Time Frame)	**Emission Factors (lbs/GWh)**					
	NO_x	**SO_2**	**ROG**	**PM_{10}**	**CO**	**CO_2***
Weighted Emis. Factor†						
(1994 - 2001)	2,262	1,652	36	85	3,114	1,154,000
(2002+)	1,822	1,277	50	106	3,364	1,154,000

All emission factors incorporate a mix of resource fuel types, such as: natural gas, coal, oil, hydroelectric, geothermal, nuclear, etc.

† Weighting is based on recent out-of-state power purchases at a ratio of 2.7 GWh from the Southwest for every 1 GWh from the Pacific Northwest (California Greenhouse Gas Emission Inventory, 1990).

* The CO_2 emission factors are based on the California Greenhouse Gas Emission Inventory, 1990.

1994 ELECTRICITY REPORT: ELECTRICITY GENERATION

Currently, California is served by 57,000 MW of dependable capacity, consisting of 250 utility thermal power plants, 300 hydroelectric units and 900 independently owned electric generation facilities. California is also served by out-of-state coal plants in the Southwest region, some of which are owned by California utilities. These coal plants represent approximately 21,000 GWH of generation, about 8.5% of the total consumption.

California's generating capacity includes 5,300 MW of nuclear capacity; 2,000 MW of natural gas-fired combustion turbines; 1,600 MW of natural gas-fired combined cycles; 10,100 MW of hydroelectric; 4,200 MW of coal-fired boilers;[3] 1,900 MW of geothermal; 25,000 MW of oil/gas-fired boilers; and 1,700 MW of biomass, wind and solar. Additionally, California purchases 5,100 MW of dependable capacity from out-of-state sources (3,200 MW from the Pacific Northwest and 1900 MW from the Southwest).

3 The 4,200 MW of coal-fired boilers includes both in-state and out-of-state California Utility-owned power plants.

RESTRUCTURING ANALYSIS

The proposed restructuring of the California electricity market contains various assumptions, proposals and consequences that may change the demand and supply of electricity and thus, may change air pollution emissions from the generation sector. These changes can occur for a variety of reasons. However, it is the changes themselves that we will analyze, not their causes. The changes identified do not encompass all of the possible changes due to restructuring. We discuss these changes in terms of in-state and out-of-state emission trends, however we can not conclude whether these trends would have occurred with or without restructuring.

In-State Emissions

In most cases, the changes due to restructuring will cause emissions from the in-state generation sector to decrease as old, inefficient facilities are replaced.

New Additions

Most new additions of power plants will be subject to BACT rules and offset requirements.[4] These new facilities will have emission factors as described in **TABLE 2** and they will displace facilities that have emission factors as described in **TABLE 1**.

Distributed generation system (DGS) facilities may not trigger BACT or offset requirements, and may (or may not) be dirtier than existing older facilities. We assume that DGS technologies may include fuel cells,[5] small combustion turbines,[6] and internal combustion engine generator sets.[7] Thus, if a significant number of "dirty" DGS technologies are installed,

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4 Offsets are typically required for major facilities (the definition changes from air district to air district) at a ratio greater than 1:1. Thus the total air emissions inventory are theoretically reduced by the addition or repowering of major facilities.

5 Fuel cells combine hydrogen and oxygen to form water and residual electric potential. Currently, fuel cells run on the hydrogen in natural gas, so they emit NO_x and CO as well as water. There are very few emissions associate with fuel cells compared to fossil-fueled combustion technologies, however fuel cells are very new so their reliability and costs are uncertain.

6 Small turbine generators (without heat recovery steam generators) do not use fuel efficiently, so their emission factors are greater relative to an existing combined cycle (see **TABLE 1**). New developments may make it possible to site these combustion turbines as part of the DGS, with emission factors similar to new combined cycles (see **TABLE 3**).

7 Internal combustion engine generator sets are the cheapest but most polluting of the potential DGS technologies. The potential for the exclusive use of natural gas and the continued development of emission control technologies should bring emission factors for these technologies closer to the current

emissions may increase in-state. Equally, if a significant number of "clean" DGS technologies are installed then emissions in-state could decrease. At this point, therefore, it is impossible to judge whether this technology will be beneficial to air quality.

Repowers

Repowering an existing facility changes the prime mover to a more modern device; it may trigger BACT, BARCT, and/or offset requirements in most cases. Thus, a repower will reduce emissions two ways: by increasing on-site capacity and displacing existing older facilities with a new "clean" generation source, and by eliminating the old facility that was repowered. So, repowers should reduce in-state emissions.

Running Existing Facilities

Continuing to run an existing facility under the same operational constraints (if any) should not result in either an increase or a decrease in in-state emissions. If the operational constraints are relaxed, then offset requirements should apply, so there should be a net decrease in emissions. If there are no operational constraints, or offset requirements do not apply, and generation is increased at the facility, then there could be an increase in in-state emissions.

Retrofits

Retrofits are often done as a consequence of BARCT requirements. Thus a retrofitted facility will emit less, but should not have a capacity increase (as in the case of a repower). This can result in a decrease in in-state emissions due to lower emission rates from the modified facility.

Replacements

Replacing an existing facility with a new facility may result in a decrease in in-state emissions. However, if the facility being replaced is a non-polluting facility (e.g., a nuclear or hydroelectric power plant), then the emission reduction might not be as much (or it may actually increase emissions) as if the original facility fired fossil fuel. Whether emissions increase or decrease when replacing a nuclear power plant with a new combined cycle depends on whether there is an increase in available capacity at the site. If there is an increase in capacity, then there will likely be a decrease in in-state emissions. If there is not an increase in capacity, then there will likely be an increase in in-state emissions.

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system average.

Retirements

Retiring an existing facility eliminates it as an electric generation resource. If the retired facility is a nuclear power plant then there may be an increase in emissions in-state and/or out-of-state. If the facility is fossil fuel fired (and it was not retired as a result of a new addition, repower or replacement), then there may be an emission increase in-state and/or out-of-state. Emission increases from either of these retirements would be the result of making up lost generation with existing facilities, not considering new additions, repowers or replacements. Countering this would be the likelihood that the retired facilities were not run much, thus they did not pollute much and it would be trivial to make up their generation. So, when a facility is retired it may increase, decrease or have little (or no) effect on emissions.

Out-of-State Emissions

If there is available capacity from out-of-state resources, and if those resources are competitive with in-state resources, then we expect to see out-of-state emissions increase due to increased California power purchases. Compared to in-state, new additions out-of-state are far less likely to displace existing out-of-state resources, therefore additional generation out-of-state will most likely increases emissions. According to out-of-state utility expansion plans, serviceable loads and available resource capacity are converging. This means that even though new out-of-state resources may come on line, they will most likely be dispatched against new load, and less likely to displace existing resources.

CONCLUSIONS

The results described above are based on a qualitative comparison of emission factors, however, they generally indicate that the near-term emissions benefits in-state will be realized by replacing the existing system with a cleaner, more efficient system. This analysis does not take into account the effect of diminished returns on such a benefit. The effect of diminished returns on the benefit of reduced in-state emissions is two fold. First, as a new power plant (or repower, replacement, etc) comes on-line it initially displaces older, less efficient facilities. This displacement, however, is generally dissipated after only a few years (due to the growth in demand). Second, after a number of new additions, the initial displacement is curtailed because the system is no longer as inefficient as it once was, therefore, emissions will eventually increase as demand increases in the far-term. These effects can only be described by production cost modeling. However, the necessary assumptions for production cost modelling will not be available until the ultimate out-come of restructuring is better known.